30 kW and Larger Interconnection Procedures Workgroup U-15113

Comments Received

On the

Staff Strawman Proposals dated June 19, 2007

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MPSC Staff Strawman Proposals for Improvements to Interconnection Procedures

DRAFT Document for Discussion at June 19, 2007 Meeting of 30 kW & Larger Interconnection Procedures Workgroup

INTRODUCTION

MPSC Staff has reviewed all comments received to date. In the following strawman proposal, Staff has attempted to accommodate, as best as possible, all comments. Staff presents this strawman proposal with the intention of leading to a productive dialogue and consensus on as many aspects of the proposal as possible.

Staff has categorized all comments into the following major categories:

- 1. Timelines, and ideas for developing reasonable and achievable timelines;
- 2. Interconnection costs, and ideas for assuring project developers will pay reasonable and actual costs;
- 3. Consultations with transmission utilities, and ideas about who will be responsible for consulting with transmission utilities, under what circumstances, etc.; and,
- 4. Identifying areas of opportunity for distribution system interconnections, where interconnection costs will be as low as possible and even where interconnection of distributed generation could reduce or avoid utility system costs.

In addition to those issues, Staff is researching:

- 5. Other miscellaneous issues raised in comments, but not covered in one of the previous four topic areas (including: insurance requirements and liabilities; pre-approved equipment lists; etc.); and
- 6. Possible power factor requirements for interconnected distributed generators.

Here are preliminary MPSC Staff recommendations for consideration. It should be noted that although the focus of this work group is on interconnections for systems 30 kW and larger, many of the concepts being discussed here could also be applicable to systems smaller than 30 kW.

As a matter of general perspective regarding the recommendations that will ultimately issue from this workgroup process, MPSC Staff has a preference for recommendations that can be adopted by consensus, and will improve the existing interconnection procedures to the extent possible, without having to await a new rulemaking proceeding to alter the existing rules. The Commission already noted, however, that some recommendations may require rulemaking, and established a new docket for that purpose, Case No. U-15239. Thus, MPSC Staff has attempted in the following recommendations

¹ February 27, 2007 Order in Cases Nos. U-15113 and U-15239, pp. 6, 7, 9, 10.

to identify whether it believes each recommendation does or does not require rules changes prior to implementation.

MPSC Staff invites review and comment on these recommendations, and will present this information for discussion at a June 19, 2007 meeting at MPSC Offices, Hearing Room A, scheduled for 10 a.m. to noon.

- 1. Timelines, and ideas for developing reasonable and achievable timelines:
 - 1.1 Developers or customers may request pre-application meetings with the utility. The pre-application meeting will allow the project developer and/or customer to seek preliminary guidance from the utility regarding engineering and design alternatives, including preferred locations for interconnection (see section 4 in this list, on page 4).
 - 1.2 Utilities will note the date when an application for interconnection is received, and the utility will notify the applicant within 3 business days, in writing, that the application has been received.
 - 1.3 Utilities will notify the applicant in writing within 10 business days of the date the application is received, if the application has been determined to be incomplete. If the application is determined to be incomplete, this notification will explain to the applicant what information is missing and will provide adequate direction to the application to allow them to correct any deficiencies in the application.
 - 1.4 In general, for the time being and until any changes in timelines are completed through a rulemaking procedure, MPSC Staff recommends that the currently adopted interconnection procedures timelines be utilized, with the utility response time tolled during periods when the project is delayed due to events that are outside of the utility's control. Tolling of the utility response time will, in all cases, require notification from the utility to the applicant, in writing, explaining: (a) the date further action on the interconnection process has been delayed; (b) the reason for delay; (c) the party whose action or inaction has resulted in the reason for delay; and (d) what is required to resolve the issue and re-start the interconnection process. When the issue is resolved, then the utility will again notify the applicant, in writing, of the date when the problem or issue has been resolved and the interconnection process continues.
 - 1.5 Utility companies could stock some equipment that will be commonly used in interconnections. Utilities should first develop lists of commonly used equipment, and work with suppliers to reduce the time required to obtain equipment when it is ordered. Then, to the extent that the costs of stocking equipment are reasonable and prudent, utilities should do so.

MPSC Staff believes action can be taken to implement recommendations 1.1 through 1.5, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239.

- 2. Interconnection costs, and ideas for assuring project developers will pay reasonable and actual costs
 - 2.1 Utilities will develop conceptual cost estimates for representative installations, based on generic interconnection parameters (subject to change based on actual circumstances for a specific project).
 - 2.2 Utilities shall maintain a list of qualified contractors as required by R 460.487(5).
 - 2.3 Utilities shall be required to obtain from qualified contractors three bids for the completion of interconnection work, and the customer shall be required to pay the amount associated with lowest of the three bids. The utility may utilize its own personnel to complete the interconnection work, but may not charge the customer more than the amount associated with the lowest of the three competitive bids.

MPSC Staff believes action can be taken to implement recommendations in 2.1 through 2.3, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239.

- 3. Consultations with transmission utilities, and ideas about who will be responsible for consulting with transmission utilities, under what circumstances, etc.
 - 3.1 Utilities should determine whether distribution level interconnections are likely to affect the transmission network. If effects on the transmission system are anticipated, then the utility should notify both the Midwest Independent System Operator (MISO) and the transmission owner (TO) of the interconnection request.

Both MISO and the TO should be notified if the interconnected distributed generator: (a) is larger than 2 MW; or (b) will be capable of producing generation in excess of the minimum load on the distribution circuit. The utility shall notify the applicant, in writing, both that it has determined there is a need to notify MISO and the TO, and when the utility has completed that notification. Such notification to the three parties shall take place within not more than 10 days of the utility's receipt of a completed interconnection application.

- 3.2 As part of the notification provided under item 3.1 above, the distribution utility should inform MISO and the TO of the distribution utility's study schedule and the date by which the distribution utility needs information from MISO and the TO, to coordinate studies and consider transmission impacts, if needed. Within the timeframe requested, it is expected that MISO and the TO will notify the distribution utility whether they will be a participant in the study or do not believe additional analysis of the transmission system impacts is warranted at that time.
- 3.3 The utility should request that MISO and the TO: (a) acknowledge receipt of the notification within not more than three business days; and (b) notify the utility of their interest in participating in system studies within not more than 10 business days.

MPSC Staff believes action can be taken to implement recommendations 3.1 through 3.3, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239. Staff notes that MPSC does not have regulatory authority over MISO or Michigan transmission owners, who are the subject of recommendation 3.2 and at least partly of recommendation 3.3. Staff understands that MISO and TOs are ready and willing to cooperate with this proposed procedure, and Staff seeks guidance from interested parties about this recommendation.

- 4. Identifying areas of opportunity for distribution system interconnections, where interconnection costs will be as low as possible and even where interconnection of distributed generation could reduce or avoid utility system costs.
 - 4.1 MPSC Staff believes this recommendation must be considered for three different types of interconnection location decisions: (1) on or adjacent to the premises of a single customer; (2) within a small prescribed area defined by the applicant or system developer; and (3) within larger areas identified by the utility company. Whenever possible, the utility company should provide information suitable for decision making regarding (1) and (2) at or as soon as possible following a pre-application meeting with the applicant and/or developer. Information regarding the third type of location decision should be developed by the utility and made available to all interested parties, with updates no less frequent than every 24 months.
 - 4.2 For type (1) decisions, the utility shall notify the customer of interconnection options and the likely costs associated with interconnecting at any reasonable point on or very near to the customer's premises.
 - 4.3 For type (2) decisions, the applicant or system developer will be responsible for letting the utility know the general area where an interconnection is proposed, and/or a choice of possible locations. For example, a project

might be proposed for installation anywhere within an area that is a specific distance from a specified point on the utility network, or another project might be proposed for installation at any of several multiple properties all owned or controlled by one entity.

For both type (1) and (2) decisions, the utility shall determine whether system studies are required in order to determine specific information adequate to provide the applicant or developer with reasonably accurate information upon which an interconnection location decision can be made. If the utility determines that further study is required, then the utility should notify the applicant or developer of that fact, and provide a schedule for the completion of that study.

4.4 For type (3) decisions, the utility should develop a map that indicates locations that are most suitable for the interconnection of distributed generation and are most likely to minimize interconnection costs. MPSC Staff is aware of similar efforts at Pacific Gas & Electric (reported in Lovins, et al., 2002, *Small is Profitable*), Commonwealth Edison, and Consolidated Edison, 2006, DSM 'Load Relief' RFP).

MPSC Staff believes action can be taken to implement recommendations 4.1 through 4.4, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239.

- 5. Other miscellaneous issues raised in comments
 - 5.1 Liability insurance. Comment from one developer is that additional liability insurance is unnecessary. MPSC Staff notes that insurance provisions are not presently included in Michigan's interconnection rules, but the Commission did approve the interconnection procedures document which explains that insurance and liability will be among those subjects covered in the utility interconnection and operating agreement.

It would be imprudent for a generator not to have ample insurance coverage, but MPSC Staff does not believe the existing rules allow the utility company to require any specific coverage. Interconnection contracts may include a statement to the effect that the generator acknowledges and accepts their potential liability in the event of an accident, however.

MPSC Staff recommends that all interested parties review the Wisconsin PSC Chapter 119 Rules for Interconnecting Distributed Generation Facilities, part PSC 119.05, and consider whether the Wisconsin insurance and indemnification provisions should be applicable for Michigan, too. (See http://www.michigan.gov/documents/mpsc/30 and Larger April 20 Comments 194118 7.pdf, pp. 9-10.)

- 5.2 Streamlining engineering studies. Recommendation is that utilities should make a determination quickly, whether studies are needed. MPSC Staff supports this concept, and believes this goal can be met by incorporating the recommendations listed under 1 through 4, above.
- 5.3 Simplified one-line diagrams. Recommendation is that the one-line diagrams required by utilities are presently too complex and should allow for further simplification. MPSC Staff seeks further clarification on this issue, and invites interested parties to submit more specific information.
- 5.4 Standby rates. Recommendation is that standby rates are presently excessive and should be lowered. MPSC Staff notes this issue is beyond the scope of the interconnection procedures process being investigated in U-15113, and suggests that interested parties address this issue in utility rate cases or other appropriate venues. MPSC Staff notes it believes that MISO Midwest Market rates are now available to provide backup power to customers, as needed, in lieu of purchasing standby and backup service from the utility company.
- 5.5 Criteria/Standards for Grid Interface Equipment. Comments state that requiring utility grade equipment is unnecessary and that industrial grade relays should be sufficient. MPSC Staff believes that decisions about equipment specifications should be determined by the appropriate national or international standards. IEEE 1547 specifies the performance that an interconnected system must meet. For customer-purchased equipment, the requirement should be for the interconnected system to meet performance specifications subject to utility verification through a witnessed test –, and the customer should have discretion regarding equipment grade.

Comments also recommend that interface equipment be standardized, insofar as that is possible. This issue is addressed in recommendations 1.5 and 2.1.

- 5.6 Payments/Ownership of Interface Equipment. Recommendation is that the customer should be compensated for the residual value of interconnection equipment, if any, if the customer has paid for the installation of equipment which later turns out not to be needed for that customer's installation (if the generator ceases operation, for example). MPSC Staff recommends that current accounting practices be reviewed in order to determine the practicality of implementing this type of recommendation.
- 5.7 Utility financial self-interest. Recommendation is to consider how financial incentives can be changed to make utility cooperation with interconnections to be in the financial interest of the utility. MPSC Staff notes this issue is beyond the scope of the interconnection procedures process being investigated in U-15113, and suggests that interested parties address this

issue in utility rate cases or other appropriate venues.

6. Possible power factor requirements for interconnected distributed generators

MPSC Staff recommends Michigan apply the general standard that the power factor requirements for distributed generators should match the requirements for customer loads, for the rate under which the distributed generation customer is served. MPSC Staff recommends Michigan utilize this language from the recently approved Maryland interconnection standards:

Reactive Power

The Interconnection Customer shall design its Small Generator Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the power factor range required by the [utility's] applicable tariff for a comparable load customer. [The utility] may also require the Interconnection Customer to follow a voltage or VAR schedule if such schedules are applicable to similarly situated generators in the control area on a comparable basis and have been approved by the Commission. The specific requirements for meeting a voltage or VAR schedule shall be clearly specified in Attachment 4. Under no circumstance shall these additional requirements for reactive power or voltage support exceed the normal operating capabilities of the Small Generator Facility.



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July 6, 2007

Ms. Julie Baldwin Michigan Public Service Commission PO Box 30221 Lansing, MI 48909-7721

Re: Case No. U-15113/U-15239

30kW and Larger Interconnection Procedures Workgroup

Dear Ms. Baldwin:

Attached are comments by International Transmission Company, d/b/a ITC*Transmission* ("ITC") and Michigan Electric Transmission Company, LLC ("METC") in response to Michigan Public Service Commission Staff's June 19, 2007 Strawman Proposal for improvements to interconnection procedures. ITC and METC own the majority of transmission system in the Lower Peninsula of Michigan. As a transmission asset owner, one of ITC's activities is the interconnection of new generating sources and the reliable transmission of the electricity generated at these facilities.

ITC and METC thank you for the opportunity to offer comments on Staff's Strawman Proposal. Because this is a workgroup, it is ITC's and METC's understanding that its comments do not need to be officially filed in this docket.

If you have any questions, please contact me.

Sincerely,

DYKEMA GOSSETT PLLC

Christine Mason Soneral

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RESPONSE OF INTERNATIONAL TRANSMISSION COMPANY, d/b/a ITCTRANSMISSION, AND MICHIGAN ELECTRIC TRANSMISSION COMPANY, LLC TO MICHIGAN PUBLIC SERVICE COMMISSION STAFF'S JUNE 19, 2007 STRAWMAN PROPOSALS FOR IMPROVEMENTS TO INTERCONNECTION PROCEDURES IN CASE NO. U-15113

International Transmission Company, d/b/a ITC*Transmission*, and Michigan Electric Transmission Company, LLC ("METC") state the following regarding the Michigan Public Service Commission ("MPSC") Staff's June 19, 2007 Strawman Proposal for improvements to interconnection procedures:

1. Timelines, and ideas for developing reasonable and achievable timelines:

- A. The transmission company must be involved in the generation interconnection process from the initial consultation/pre-application meeting.
- B. The transmission company should assess if the new generator(s) will affect the transmission system.
- C. The aggregated output of a group of generators in an electrical area is the driving factor to be considered.
- D. Transmission design and guidance is only performed by the transmission company so it is essential that transmission be involved in the initial stages of interconnection discussions.
- E. Depending on how the generation is planned to be interconnected (to the distribution or transmission system) determines whether MPSC state procedures or Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") Federal Energy Regulatory Commission ("FERC") approved procedures governs.
- F. Notification needs to be provided to MISO as it is responsible for regional transmission planning.

2. <u>Interconnection costs, and ideas for assuring project developers will pay reasonable and actual costs.</u>

- A. Are these "interconnection costs" or "network upgrade" costs?
 - 1.) Direct assignment.
 - 2.) Network upgrades.
- B. Determine if the new generator(s) is(are) connecting at the distribution level (MPSC procedures) or the transmission level (Midwest ISO FERC approved procedures).
- C. Follow "decision tree" to determine whether state or federal procedures should be followed.
 - 1.) For transmission level connections, follow the Midwest ISO generation interconnection procedures as contained in Attachments X and R. The transmission company would be involved in this process.
 - For distribution level connections, follow MPSC procedures. The local distribution utility would be involved in this process and the transmission company would also be involved to the extent the proposed interconnection has an impact on the transmission system.
- 3. <u>Consultations with transmission utilities, and ideas about who will be responsible for consulting with transmission utilities, under what circumstances, etc.</u>
 - A. Consultation with the transmission company needs to occur at the beginning of the process.
 - B. All generator interconnection notification should be provided to the transmission company.

LAN01\174545.2 ID\CMMA July 6, 2007

To: Julie Baldwin

Michigan Public Service Commission

Re: Comments on power factor correction for 30kW and Larger Interconnection

Procedures Workgroup

Dear Ms. Baldwin,

Thank you for the opportunity to comment on 30 kW interconnection issues. Please find below some general comments regarding the power factor correction issues.

It was observed by participants during the meeting on June 19, 2007 that power factor correction is primarily an economic issue, as the technical factors for correcting generator output are well known and quantifiable. This fact is evident in the past filings of Detroit Edison and Consumers Energy, which contain penalties for poor power factor and incentives for desired power factor, which should be expanded and clarified for the purposes of this workgroup.

I have provided below a short review of power factors which addresses both lagging and leading power factors, some supporting data on power factor treatment, and several suggestions below for fair treatment of all parties on power factor issues.

Power Factor 101

As stated by the DTE presentation, a "unity" power factor of 1.0 is optimal, but realities of load and generator interaction cause this power factor to vary over time. Power factor at a meter can "lag" the grid (i.e. draw extra energy "vars" from the grid), or "lead" the grid (i.e. inject energy "vars" into the grid). Power factors commonly found on power grids range from an undesirable 0.7 lagging, improving towards 0.99 lagging and 1.0 (unity), then transitioning to the less common leading power factors from 0.99 leading to 0.7 leading. One way to form a mental picture of power factor is to view it as the variance from the optimum of 1.0 (unity), which may exhibit a drift in either direction (lagging/leading) until the drift reaches an unacceptable point (e.g. 0.7) and must be corrected.



Utility Treatment of Power Factors

There are acceptable ranges of this leading and lagging which the utilities have included in their rate filings for numerous rates. Let's quickly review those for loads:

Power Factor	DTE Filing	Consumers Filing
Below 0.7 lagging	Can disconnect customer	Can disconnect customer
Between 0.7 to 0.75 lagging	3% financial penalty	Financial penalty calculated
		below 0.8 power factor
Between 0.75 to 0.8 lagging	2% financial penalty, or	Same calculation as above
	\$3.50/KVar below 0.8	
	lagging	
Between 0.8 to 0.85 lagging	1% financial penalty	No penalty
Between 0.8 to 0.9 lagging	Desired power factor	Desired Power factor
Between 0.9 lagging and	Not addressed	2% incentive (rebate)
1.0		
Leading power factor	Not addressed	Not addressed

Financial penalties are typically not addressed for non-excessive leading power factors as these are desirable in most instances as they directly offset (more prevalent) equivalent lagging power factors (i.e. a .8 leading power factor on 30kW directly offsets as .8 lagging power factor on 30kW at the same connection point).

Regarding the treatment of power factor correction from generation connections, one can review FERC Docket No. ER06-348-000, in which a generator in Michigan requested over \$1.3MM per year in remuneration from MISO to provide power factor correction on the grid as per Schedule 2 of the MISO tariff. Note that this generator was not expected to generate at unity power factor, and in fact expected to receive guaranteed payment for power factor support.

The above facts demonstrate that there is significant precedent in both financial penalty for undesirable power factors as well as financial incentive for desirable power factors.



Given the above observations, please find below some suggestions for fair and balanced treatment of generation interconnection.

Suggestions for Power Factor Treatment for Interconnections

- 1. Any party seeking to assess penalties for undesirable power factors should also be required to provide equivalent incentive payments for desirable power factors.
- 2. Costs that are presented as necessary for correction of power factor should be open for bid by third parties. As an example, the presentation by DTE on June 19, 2007 presents a cost of \$20,000 per MVAR for power factor correction. If a third party can offer power factor correction for less than this rate, then they should be encouraged to do so.
- 3. Generators should not be required to connect at unity power factor, but should have a strong incentive for connection at a desired power factor. A range of penalties and incentives for connection at various power factors should be specified, including bandwidths of power factors as shown in utility rates. Unity power factor should have neither incentives or penalties.

Thank you,

Donald Lechnar

Don.Lechnar@opknowledge-advisors.com



MPSC Staff Strawman Proposals for Improvements to Interconnection Procedures

DRAFT Document for Discussion at June 19, 2007 Meeting of 30 kW & Larger Interconnection Procedures Workgroup

INTRODUCTION

MPSC Staff has reviewed all comments received to date. In the following strawman proposal, Staff has attempted to accommodate, as best as possible, all comments. Staff presents this strawman proposal with the intention of leading to a productive dialogue and consensus on as many aspects of the proposal as possible.

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- 3. Consultations with transmission utilities, and ideas about who will be responsible for consulting with transmission utilities, under what circumstances, etc.; and,
- 4. Identifying areas of opportunity for distribution system interconnections, where interconnection costs will be as low as possible and even where interconnection of distributed generation could reduce or avoid utility system costs.

In addition to those issues, Staff is researching:

- 5. Other miscellaneous issues raised in comments, but not covered in one of the previous four topic areas (including: insurance requirements and liabilities; pre-approved equipment lists; etc.); and
- 6. Possible power factor requirements for interconnected distributed generators.

Here are preliminary MPSC Staff recommendations for consideration. It should be noted that although the focus of this work group is on interconnections for systems 30 kW and larger, many of the concepts being discussed here could also be applicable to systems smaller than 30 kW.

As a matter of general perspective regarding the recommendations that will ultimately issue from this workgroup process, MPSC Staff has a preference for recommendations that can be adopted by consensus, and will improve the existing interconnection procedures to the extent possible, without having to await a new rulemaking proceeding to alter the existing rules. The Commission already noted, however, that some recommendations may require rulemaking, and established a new docket for that purpose, Case No. U-15239. Thus, MPSC Staff has attempted in the following recommendations

¹ February 27, 2007 Order in Cases Nos. U-15113 and U-15239, pp. 6, 7, 9, 10.

to identify whether it believes each recommendation does or does not require rules changes prior to implementation.

Michigan Electric Industry Comments

These comments are the joint effort of the regulated electric utilities including the members the Michigan Electric and Gas Association and the Michigan Electric Cooperative Association as well as DTE Energy (Detroit Edison) and Consumers Energy (collectively "Utilities"). The Staff Strawman proposal is reproduced verbatim in black ink, with the Utility comments in relevant places in blue ink and italicized for non-color printings.

Although this work group process is addressing interconnection of projects sized at 30 kW and up, experience and the type of project developers participating in the process indicate that the focus is still on "smaller" projects, likely to be sized at 2 megawatts (MW) or less. The larger independent generator interconnections tend to be worked out on a project specific basis, without the need for Commission oversight or complaint resolution. The developers of larger projects are typically experienced entities and there are likely to be multiple Utility employees devoted to the project.

MPSC Staff invites review and comment on these recommendations, and will present this information for discussion at a June 19, 2007 meeting at MPSC Offices, Hearing Room A, scheduled for 10 a.m. to noon.

- 1. Timelines, and ideas for developing reasonable and achievable timelines:
 - 1.1 Developers or customers may request pre-application meetings with the utility. The pre-application meeting will allow the project developer and/or customer to seek preliminary guidance from the utility regarding engineering and design alternatives, including preferred locations for interconnection (see section 4 in this list, on page 9).
 - The general premise of holding a pre-application meeting with a potential Project Developer (PD) or Customer on request is acceptable to Utilities. The pre-application meeting obligation should not be open ended for a single project the meeting should be limited to not more than two (2) separate occasions or a total of 4 hours. This will encourage advance preparation by PDs and efficient use of time by the Utility employees.
 - 1.2 Utilities will note the date when an application for interconnection is received, and the utility will notify the applicant within 3 business days, in writing, that the application has been received.

This is acceptable to Utilities and consistent with the existing Generator Interconnection Requirements (GIR). Reasonable means of electronic

communication such as e-mail and fax should be allowed for this notification.

1.3 Utilities will notify the applicant in writing within 10 business days of the date the application is received, if the application has been determined to be incomplete. If the application is determined to be incomplete, this notification will explain to the applicant what information is missing and will provide adequate direction to the application to allow them to correct any deficiencies in the application.

This is consistent with the existing Generator Interconnection Requirements (GIR); however, actual experience indicates this time period is not sufficient to fully address an application particularly where there are multiple applications and interconnection processes under review by a single Utility. For these larger units the Utilities suggest a time period of 1 month for review and notification of missing information in the application. This will provide an incentive for PDs to make sure the application is complete. In some cases, even a complete application may indicate a need for additional information concerning the project. If preliminary analysis shows such a need, the Utility should advise the PD and be allowed 2 months to respond. The "pre-meeting" process will provide an initial opportunity for information exchange between the parties to mitigate delay.

1.4 In general, for the time being and until any changes in timelines are completed through a rulemaking procedure, MPSC Staff recommends that the currently adopted interconnection procedures timelines be utilized, with the utility response time tolled during periods when the project is delayed due to events that are outside of the utility's control. Tolling of the utility response time will, in all cases, require notification from the utility to the applicant, in writing, explaining: (a) the date further action on the interconnection process has been delayed; (b) the reason for delay; (c) the party whose action or inaction has resulted in the reason for delay; and (d) what is required to resolve the issue and re-start the interconnection process. When the issue is resolved, then the utility will again notify the applicant, in writing, of the date when the problem or issue has been resolved and the interconnection process continues.

The rulemaking time deadlines are proving unworkable in practice and development of more reasonable time periods should not be deferred. The time intervals in the Michigan rules are shorter than those of other states and pose a considerable burden for smaller utilities and cooperatives. The Michigan rules (R 460.486) adopt stated deadlines for completing all of a utility's obligations for interconnection for each of the 5 size category ranges. This approach is more reasonable where a proposed interconnection requires no distribution system modifications (e.g.

typically 10kW and less projects). As generator size increases the likelihood of required system modifications increases. System modifications require longer interconnection timelines. Utilities suggest that the Commission consider the interconnection deadline approach used in Wisconsin's Rule 119 (Attachment No. 1). Rule 119 provides deadlines for steps of the project (engineering review, distribution study and final testing) for the project size categories.

In developing timelines, consideration should be given to situations where there are numerous applications for interconnection exceeding the ability of a Utility to effectively process them consistent with the deadlines. Strict enforcement and sanctions under the present rules should not be adopted because of the experience with many projects requiring additional time.

Utilities support the Strawman concept of tolling the deadlines for circumstances beyond their control. The Michigan rule differs insofar as it recognizes tolling for right-of-way procurement/zoning and PD delays only. The detailed notification requirements suggested in the Strawman could be counterproductive, however. It is reasonable to give notice of tolling and address the reasons. Utilities already track problems that arise with any interconnection project. Requiring a written listing of the reasons, assignment of fault, and actions needed to re-start the clock may lead to an overabundance of caution and excessive formality because the document is likely to become the focal point in any complaint proceeding.

A starting point for discussions leading to improvement of the time deadlines could be the periods and size categories in Wisconsin Rule 119. The Wisconsin size categories could easily be modified to fit the current 5 Michigan categories. The remaining steps in the process involve the utility completing detailed design, engineering, procurement of equipment, right of way, and final construction. The details of these parts of the timeline are not in the Wisconsin rule and need to be addressed..

The current GIR also requires that the utility provide a good faith cost estimate of the project cost immediately after the application is complete, without a study having been completed, and with a two hour consultation. Such a cost estimate is nothing more than a guess. In fact, interconnection of generation projects may actually be infeasible at some locations in the utility and may be rejected pending an interconnection study. Providing a cost estimate at that stage in the process timeline is clearly an unreasonable requirement that should be eliminated.

1.5 Utility companies could stock some equipment that will be commonly used in interconnections. Utilities should first develop lists of commonly used equipment, and work with suppliers to reduce the time required to obtain

equipment when it is ordered. Then, to the extent that the costs of stocking equipment are reasonable and prudent, utilities should do so.

Utilities may be able to stock some commonly used equipment with long lead times in an attempt to help expedite the interconnection process. This practice could give rise to other issues, since there are costs associated with stocking commonly used equipment (~7-10% loadings) and the time of use is uncertain. Most PD's will likely view the carrying costs as unreasonable; alternatively, other customers may object to these costs being absorbed by the utility creating a subsidy. The decision to stock items should be left to individual Utilities based on their own policies and experience. The policy should be consistent with the stocking of equipment to assure reliable service for general utility customers.

MPSC Staff believes action can be taken to implement recommendations 1.1 through 1.5, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239.

As stated above, additional collaboration is warranted in order to develop more reasonable and achievable interconnection timelines. A piecemeal approach may not be the best way to address the interconnection issues, particularly if there is interest in a framework similar to Wisconsin Rule 119.

2. Interconnection costs and ideas for assuring project developers will pay reasonable and actual costs.

This process should not assume PDs are being charged unreasonable or excessive costs. Generally, Utilities provide the interconnection services at their cost, which includes standard overheads. Utilities also provide expertise through their trained personnel and may provide the cost advantage of equipment purchased in bulk.

2.1 Utilities will develop conceptual cost estimates for representative installations, based on generic interconnection parameters (subject to change based on actual circumstances for a specific project).

This proposal acknowledges that project interconnection costs will vary based on the circumstances of individual projects. Thus any generic parameters are likely to vary from actual costs and lead to tension and possible controversy. The conceptual costs will likely be treated as a benchmark for comparison by PDs, if the actual costs turn out to be higher. Utilities would then have an incentive to provide high estimates to protect against future controversy. In the experience of some utilities, PDs are looking for more concrete cost estimates in order to securing

project financing. Lenders are not likely to accept the generic figures without some assurance they are close to the actual costs.

A possible alternative to the proposal would be to hold pre-application meetings, and develop preliminary cost estimates based on proposed sites versus blanket conceptual estimates.

2.2 Utilities shall maintain a list of qualified contractors as required by R 460.487(5).

This is acceptable and consistent with existing practices. Contractors are typically subject to direct utility supervision. Customers are not permitted to work on utility assets.

2.3 Utilities shall be required to obtain from qualified contractors three bids for the completion of interconnection work, and the customer shall be required to pay the amount associated with lowest of the three bids. The utility may utilize its own personnel to complete the interconnection work, but may not charge the customer more than the amount associated with the lowest of the three competitive bids.

As noted, there should be no assumption that PDs are being charged unreasonable and excessive interconnection costs. This recommendation will create multiple new issues and add to the complexity of the interconnection process. The last sentence in particular may give rise to issues under the collective bargaining agreements of utilities. Introducing a competitive bidding process will add all f the difficulties and uncertainties associated with bidding: What happens with "scope creep" after the bid is accepted? Will disgruntled bidders commence litigation? Who should police the fairness of the bidding process?

A competitive bid process eliminates parallel path opportunities and preplanning during the project engineering. Engineering work packets will need to be 100% complete before the bid package can be submitted to the contractors for bid development. Engineering time may have to be extended to ensure all unknowns are accounted for in the bid package. If additional work is identified during construction, time delays may result from contract change orders, and customer approvals for the change orders. The project would be subject to contractor availability, contractor bids may not be as timely if work is plentiful.

Introducing a competitive bidding process for interconnections will raise an issue of discriminatory pricing vis-à-vis other utility customers. The issue underlying this recommendation relates to utility cost and overheads. All bundled retail customers are required to pay the accepted accounting overheads on new business, premium service, relocation and system modification projects. The generator should be billed according to the same practices/processes as other Utility customers. For example, if a phase extension is required for the interconnection, the PD should pay the same line extension charges as would apply to another customer seeking phase extension.

MPSC Staff believes action can be taken to implement recommendations in 2.1 through 2.3, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239.

For the reasons stated above, implementation of Recommendations 2.1 and 2.3 is not appropriate action.

- 3. Consultations with transmission utilities, and ideas about who will be responsible for consulting with transmission utilities, under what circumstances, etc.
 - 3.1 Utilities should determine whether distribution level interconnections are likely to affect the transmission network. If effects on the transmission system are anticipated, then the utility should notify both the Midwest Independent System Operator (MISO) and the transmission owner (TO) of the interconnection request.

Both MISO and the TO should be notified if the interconnected distributed generator: (a) is larger than 2 MW; or (b) will be capable of producing generation in excess of the minimum load on the distribution circuit. The utility shall notify the applicant, in writing, both that it has determined there is a need to notify MISO and the TO, and when the utility has completed that notification. Such notification to the three parties shall take place within not more than 10 days of the utility's receipt of a completed interconnection application.

Utilities would typically make the determination and notify the applicable RTO (MISO, or PJM in the case of Indiana Michigan Power Company) under the RTO's procedures. Notice to the appropriate regional reliability organization may be a consideration. In situations affecting the transmission network, the PD is responsible for interactions with the RTO and TO. The timing for transmission review and studies is beyond the control of the Utilities or Michigan regulation.

3.2 As part of the notification provided under item 3.1 above, the distribution utility should inform MISO and the TO of the distribution utility's study schedule and the date by which the distribution utility needs information from MISO and the TO, to coordinate studies and consider transmission

impacts, if needed. Within the timeframe requested, it is expected that MISO and the TO will notify the distribution utility whether they will be a participant in the study or do not believe additional analysis of the transmission system impacts is warranted at that time.

Any coordination of transmission and distribution studies and related

Any coordination of transmission and distribution studies and related timing issues will need to be worked out among the interested parties on a case-specific basis.

3.3 The utility should request that MISO and the TO: (a) acknowledge receipt of the notification within not more than three business days; and (b) notify the utility of their interest in participating in system studies within not more than 10 business days.

Any coordination of transmission and distribution studies and related timing issues will need to be worked out among the interested parties on a case-specific basis. Utilities have no standing to impose time deadlines on the transmission entities.

MPSC Staff believes action can be taken to implement recommendations 3.1 through 3.3, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239. Staff notes that MPSC does not have regulatory authority over MISO or Michigan transmission owners, who are the subject of recommendation 3.2 and at least partly of recommendation 3.3. Staff understands that MISO and TOs are ready and willing to cooperate with this proposed procedure, and Staff seeks guidance from interested parties about this recommendation.

These recommendations are affected by the lack of Michigan regulatory authority over the transmission entities, as acknowledged above. Any procedures in this area should be worked out on a voluntary and project specific basis to provide experience regarding what is feasible. It is premature and probably unnecessary to assign PD obligations in dealing with the transmission entities to the Utilities and providing time deadlines to those entities.

4. Identifying areas of opportunity for distribution system interconnections, where interconnection costs will be as low as possible and even where interconnection of distributed generation could reduce or avoid utility system costs.

Typically, small generator projects are located at specific existing sites already chosen by the customer, such as the customer's current residence or small business location. As a general rule of thumb, the probability of lower interconnection costs increases as the site is located closer to a substation.

This proposed course of action suggests imposition of an obligation on Utilities to perform engineering study work on behalf of PDs who will then displace Utility load and revenue and seek compensation for excess generation, while assuming none of the public duties associated with public utility service. This is a major public policy issue. Further, Utilities would be placed in the position of assuming significant administrative duties and costs, because the dynamic nature of utility systems would require a constant re-evaluation of the optimal DG locations. Circuits are constantly in a state of flux with load being shifted from one circuit to another, circuits being upgraded or modified, equipment being changed out, etc. It would require a constant and significant effort to update the distribution system status, as affected by time of day, time of year, equipment outages, system load and other factors. Presumably, the costs of this effort would be subsidized by the Utility customer base. Further, with the dynamic system there can be little guarantee that a designated interconnection point will remain optimal from the PD's viewpoint. Thus, the recommendation would create a risk of litigation based on alleged breach of this new "duty" to provide the best location information.

Finally, caution and a concern for public safety and security mitigate against a requirement for the detailed public disclosure of distribution weak points and other system information.

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4.1 MPSC Staff believes this recommendation must be considered for three different types of interconnection location decisions: (1) on or adjacent to the premises of a single customer; (2) within a small prescribed area defined by the applicant or system developer; and (3) within larger areas identified by the utility company. Whenever possible, the utility company should provide information suitable for decision making regarding (1) and (2) at or as soon as possible following a pre-application meeting with the applicant and/or developer. Information regarding the third type of location decision should be developed by the utility and made available to all interested parties, with updates no less frequent than every 24 months.

For the type (1) and type (2) situations, the optimal interconnection point can be addressed through the established procedures, including the preapplication meeting. The type (3) situation is subject to all of the concerns discussed above.

4.2 For type (1) decisions, the utility shall notify the customer of interconnection options and the likely costs associated with interconnecting at any reasonable point on or very near to the customer's premises.

This proposal is generally acceptable, since the customer would be approaching the Utility with a project and a proposed location.

4.3 For type (2) decisions, the applicant or system developer will be responsible for letting the utility know the general area where an interconnection is proposed, and/or a choice of possible locations. For example, a project might be proposed for installation anywhere within an area that is a specific distance from a specified point on the utility network, or another project might be proposed for installation at any of several multiple properties all owned or controlled by one entity.

This proposal is generally acceptable, since the possible location options are determined by the PD and the Utility would then be assisting the PD in its selection of the preferable interconnection point based on the local system.

For both type (1) and (2) decisions, the utility shall determine whether system studies are required in order to determine specific information adequate to provide the applicant or developer with reasonably accurate information upon which an interconnection location decision can be made. If the utility determines that further study is required, then the utility should notify the applicant or developer of that fact, and provide a schedule for the completion of that study.

The PD should have the responsibility of determining what information or study is needed to make its decision on the location of the interconnection. Utilities should not be assigned the duty and responsibility to make project location decisions for the PDs. Interconnection studies (of some degree, even if simple) will be required for any project interconnection.

4.4 For type (3) decisions, the utility should develop a map that indicates locations that are most suitable for the interconnection of distributed generation and are most likely to minimize interconnection costs. MPSC Staff is aware of similar efforts at Pacific Gas & Electric (reported in Lovins, et al., 2002, *Small is Profitable*), Commonwealth Edison, and Consolidated Edison, 2006, DSM 'Load Relief' RFP).

This entire area of "type (3)" decisions is subject to the earlier general comment regarding the roles of the utility and PD as well as concerns for security and cost responsibility. In effect, this recommendation appears to contemplate a major assigned role to Utilities to perform widespread location work on behalf of potential developers, with the costs borne by the utilities and their customers.

MPSC Staff believes action can be taken to implement recommendations 4.1 through 4.4, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239.

As noted, the Utilities have major concerns over the Type (3) decision proposals in this section.

5. Other miscellaneous issues raised in comments

5.1 Liability insurance. Comment from one developer is that additional liability insurance is unnecessary. MPSC Staff notes that insurance provisions are not presently included in Michigan's interconnection rules, but the Commission did approve the interconnection procedures document which explains that insurance and liability will be among those subjects covered in the utility interconnection and operating agreement.

It would be imprudent for a generator not to have ample insurance coverage, but MPSC Staff does not believe the existing rules allow the utility company to require any specific coverage. Interconnection contracts may include a statement to the effect that the generator acknowledges and accepts their potential liability in the event of an accident, however.

MPSC Staff recommends that all interested parties review the Wisconsin PSC Chapter 119 Rules for Interconnecting Distributed Generation Facilities, part PSC 119.05, and consider whether the Wisconsin insurance and indemnification provisions should be applicable for Michigan, too. (See http://www.michigan.gov/documents/mpsc/30 and Larger April 20 Comments 194118 7.pdf, pp. 9-10.)

Many of the Utilities participating in these comments agree that the provisions for minimum liability insurance and indemnity contained in Wisconsin Rule 119.05 are workable. It is well known in Michigan that the potential liability for tort damages can be greatly influenced by the venue; accordingly, the minimum insurance coverage should be adjusted for this increased risk, for those utilities rendering service in the higher risk areas. For example, Attachment 2 contains the insurance and indemnity requirements proposed for DTE Energy. This should be discussed in the collaborative. Another approach is simply to leave this issue to each utility, subject to a general requirement of commercial reasonableness in accordance with local practices. In either case, there should be requirements applicable to the PD (installer) and the customer owning the generator during its time of use.

5.2 Streamlining engineering studies. Recommendation is that utilities should make a determination quickly, whether studies are needed. MPSC Staff supports this concept, and believes this goal can be met by incorporating the recommendations listed under 1 through 4, above.

This recommendation needs further clarification because the terms "streamlining" and "quickly" are susceptible to conflicting interpretations.

There should be no regulatory action that diminishes the quality of the engineering studies for interconnection. Engineering studies are required for <u>all</u> interconnection projects. A "cookbook" approach cannot be implemented without degrading the quality of the studies. The characteristics of the utility system are too diverse, generator size can be practically anything, and electric systems are complex. To decrease the engineering study time, the generator needs to provide the information specified in the interconnect application.

The existing MPSC Interconnection Standards are written such that the engineering study contains the analysis, system modification requirements and conceptual costs as one package – unlike other states that break the same analysis into several steps of the process, such as Wisconsin (Rule 119).

5.3 Simplified one-line diagrams. Recommendation is that the one-line diagrams required by utilities are presently too complex and should allow for further simplification. MPSC Staff seeks further clarification on this issue, and invites interested parties to submit more specific information.

A one-line diagram <u>is</u> a simplified electrical drawing. The information required on the one-line diagrams is important for understanding the project design, operation, protection scheme, etc. A complete one-line diagram can significantly speed up an engineering analysis / study / project. The information required on the one-line diagram is what the utility needs to complete a study. Oversimplification will create risks to the safety of linemen and the public.

5.4 Standby rates. Recommendation is that standby rates are presently excessive and should be lowered. MPSC Staff notes this issue is beyond the scope of the interconnection procedures process being investigated in U-15113, and suggests that interested parties address this issue in utility rate cases or other appropriate venues. MPSC Staff notes it believes that MISO Midwest Market rates are now available to provide backup power to customers, as needed, in lieu of purchasing standby and backup service from the utility company.

If Staff is taking the absolute position that standby rates are presently excessive and should be lowered, how does this accord with recent electric rate case orders approved by the Commission? There may be some confusion whether MISO provides a standby service available for retail electric customers with a small on-site generator. MISO's "station service" is designed for large electric generators with energy sales into the MISO market. Utilities disagree with the general assertion that standby rates are excessive and should be lowered. These rates are established under the general cost of service ratemaking approach.

5.5 Criteria/Standards for Grid Interface Equipment. Comments state that requiring utility grade equipment is unnecessary and that industrial grade relays should be sufficient. MPSC Staff believes that decisions about equipment specifications should be determined by the appropriate national or international standards. IEEE 1547 specifies the performance that an interconnected system must meet. For customer-purchased equipment, the requirement should be for the interconnected system to meet performance specifications – subject to utility verification through a witnessed test –, and the customer should have discretion regarding equipment grade.

Utilities must be able to control the operation, modification and maintenance of their own electric systems, which are unique and have evolved over time due to technology changes, equipment availability, service requirements and customer needs. A customer or developer cannot be provided the discretion to determine the grade of equipment they wish to connect directly to or on a utility's electrical distribution system. A utility must have the discretion to require the type and grade of equipment on its electrical system it believes to be most appropriate. While a piece of equipment described as "industrial grade" sounds robust, it may have considerably less reliability, durability or capability than a similar "utility grade" piece of equipment. Utilities are held accountable to maintain certain levels of system reliability and therefore must be permitted to control the type of equipment on their electrical systems. PD's may install protective relays of any grade the choose in order to protect their own equipment.

Comments also recommend that interface equipment be standardized, insofar as that is possible. This issue is addressed in recommendations 1.5 and 2.1.

5.6 Payments/Ownership of Interface Equipment. Recommendation is that the customer should be compensated for the residual value of interconnection equipment, if any, if the customer has paid for the installation of equipment which later turns out not to be needed for that customer's installation (if the generator ceases operation, for example). MPSC Staff recommends that current accounting practices be reviewed in order to determine the practicality of implementing this type of recommendation.

There will be little or no residual value to the utility for interconnection-related equipment (such as transfer trip, monitoring device, etc). This equipment is needed solely for the customer's interconnection. Furthermore, rates are based upon the cost of service and a regulated rate of return. The distribution cost does not decrease because a customer's generating unit shuts down. Providing compensation for residual value would shift cost from the customer that caused the cost to other customers

that did not cause the cost. This is a sunk cost of the customer's generation project, not unlike any other electrical work performed on the customer's premises that has little or no value after the generator ceases operation.

5.7 Utility financial self-interest. Recommendation is to consider how financial incentives can be changed to make utility cooperation with interconnections to be in the financial interest of the utility. MPSC Staff notes this issue is beyond the scope of the interconnection procedures process being investigated in U-15113, and suggests that interested parties address this issue in utility rate cases or other appropriate venues.

The statement implies without foundation that utilities are not cooperating with interconnections due to their financial interests. While the issue may indeed by beyond the scope of the process, it is noteworthy that many interconnections are mandated by law and cooperation is required. Lack of cooperation should not be assumed based on the efforts of utilities to recover the costs associated with providing a premium service to the PDs.

6. Possible power factor requirements for interconnected distributed generators

MPSC Staff recommends Michigan apply the general standard that the power factor requirements for distributed generators should match the requirements for customer loads, for the rate under which the distributed generation customer is served. MPSC Staff recommends Michigan utilize this language from the recently approved Maryland interconnection standards:

Reactive Power

The Interconnection Customer shall design its Small Generator Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the power factor range required by the [utility's] applicable tariff for a comparable load customer. [The utility] may also require the Interconnection Customer to follow a voltage or VAR schedule if such schedules are applicable to similarly situated generators in the control area on a comparable basis and have been approved by the Commission. The specific requirements for meeting a voltage or VAR schedule shall be clearly specified in Attachment 4. Under no circumstance shall these additional requirements for reactive power or voltage support exceed the normal operating capabilities of the Small Generator Facility.

The proposed matching principle (generator and load customer) is misplaced because the parties are not similarly situated. A load customer pays a regulated rate for electric service that includes costs of Power Factor correction supplied by the utility. A generator is not paying the Power Factor costs through the regulated rates; therefore the proposed "matching" actually creates a subsidy,

since the costs of Power Factor correction caused by the generator are passed on to the Utility and its other customers.

The Maryland Reactive Power provision cited only addresses the electrical design of the generation facility but does not address the real consequences of operating generation equipment outside of the relevant limits. Failure to operate a generator as required causes additional costs to the utility which, if not compensated by the customer who causes the cost, will ultimately be passed on to other electric customers. Accordingly, Utilities will provide adequate VAR compensation for inadequate power factor of the generator. Utilities will invoice the PD at the time of initial interconnection of the generator.

The power factor for the distributed generation installation must be set in a manner to insure proper anti-islanding separation, to minimize risks to the public and equipment of other utility customers. IEEE 1547 4.4.1 prohibits the distributed resource from causing variances in the local utility service voltage beyond established ranges. For weak local systems and rural systems, the service quality issues associated with voltage regulation and islanding can be difficult to resolve, sometimes requiring additional equipment at the project developer's expense. Utilities are expected to prevent the addition of customers or facilities from unduly impacting or degrading the quality of service to others. The proposal conflicts with this expectation and duty.

Attachment No. 1 Wisconsin Rule 119

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PSC 119.02

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Chapter PSC 119

RULES FOR INTERCONNECTING DISTRIBUTED GENERATION FACILITIES

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PSC 119.08	Fees and distribution system costs.	PSC 119.30	Anti-islanding test.
PSC 119.09	Disconnection.	PSC 119.31	Commissioning tests for paralleling equipment in Categories 2 to 4.
PSC 119.10	One-line schematic diagram.	PSC 119.32	Additional test.
PSC 119.11	Control schematics.	PSC 119.40	Right to appeal.

Subchapter I — General

PSC 119.01 Scope. This chapter implements s. 196.496, Stats. It applies to all DG facilities with a capacity of 15 MW or less that are interconnected, or whose owner seeks to have interconnected, to an electric public utility's distribution system. It also applies to all electric public utilities to whose distribution systems a DG facility is interconnected, or to which interconnection is sought. These rules establish uniform statewide standards for the interconnection of DG facilities to an electric distribution system.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

PSC 119.02 Definitions. In this chapter:

- (1) "ANSI" means American National Standards Institute.
- (2) "Applicant" means the legally responsible person applying to a public utility to interconnect a DG facility to the public utility's distribution system.
- (3) "Application review" means a review by the public utility of the completed standard application form for interconnection, to determine if an engineering review or distribution system study is needed.
 - (4) "Category 1" means a DG facility of 20 kW or less.
- (5) "Category 2" means a DG facility of greater than 20 kW and not more than 200 kW.
- (6) "Category 3" means a DG facility of greater than 200 kW and not more than 1 MW.
- (7) "Category 4" means a DG facility of greater than 1 MW and not more than 15 MW.
- (8) "Certified equipment" means a generating, control or protective system that has been certified by a nationally recognized testing laboratory as meeting acceptable safety and reliability
- (9) "Commission" means the public service commission of Wisconsin.
- (10) "Commissioning test" means the process of documenting and verifying the performance of a DG facility so that it operates in conformity with the design specifications.
- (11) "Customer" means any person who is receiving electric service from a public utility's distribution system.
 - (12) "DG" means distributed generation.
- (13) "DG facility" has the meaning given in s. 196.496 (1), Stats.
- (14) "Distribution feeder" means an electric line from a public utility substation or other supply point to customers that is operated at 50 kV or less, or as determined by the commission.

- (15) "Distribution system" means all electrical wires, equipment, and other facilities owned or provided by a public utility that are normally operated at 50 kV or less.
- (16) "Distribution system study" means a study to determine if a distribution system upgrade is needed to accommodate the proposed DG facility and to determine the cost of any such upgrade.
- (17) "Engineering review" means a study that may be undertaken by a public utility, in response to its receipt of a completed standard application form for interconnection, to determine the suitability of the installation.
- (18) "Fault" means an equipment failure, conductor failure, short circuit, or other condition resulting from abnormally high amounts of current from the power source.
- (19) "IEEE" means Institute of Electrical and Electronics Engineers.
- **(20)** "Interconnection" means the physical connection of a DG facility to the distribution system so that parallel operation can occur.
- (21) "Interconnection disconnect switch" means a mechanical device used to disconnect a DG facility from a distribution system.
- (22) "Inverter" means a machine, device, or system that converts direct current power to alternating current power.
- (23) "Islanding" means a condition on the distribution system in which a DG facility delivers power to customers using a portion of the distribution system that is electrically isolated from the remainder of the distribution system.
 - (24) "kV" means kilovolt.
 - (25) "kW" means kilowatt.
- (26) "Material modification" means any modification that changes the maximum electrical output of a DG facility or changes the interconnection equipment, including:
 - (a) Changing from certified to non-certified devices.
- (b) Replacing a component with a component of different functionality or UL listing.
 - (27) "MW" means megawatt.
- (28) "Nationally recognized testing laboratory" means any testing laboratory recognized by the U.S. Department of Labor Occupational Safety and Health Administration's accreditation program.

Note: A list of nationally recognized testing laboratories is available at www.o-sha.gov/dts/otpca/nrtl/index.html.

(29) "Network service" means 2 or more primary distribution feeders electrically connected on the low voltage side of 2 or more transformers, to form a single power source for any customer.

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- (30) "Parallel operation" means the operation, for longer than 100 milliseconds, of an on-site DG facility while the facility is connected to the energized distribution system.
- (31) "Paralleling equipment" means the generating and protective equipment system that interfaces and synchronizes a DG facility with the distribution system.
- (32) "Point of common coupling" means the point where the electrical conductors of the distribution system are connected to the customer's conductors and where any transfer of electric power between the customer and the distribution system takes place.
- (33) "Public utility" has the meaning given in s. 196.01 (5), Stats.
- (34) "Standard application form" means PSC Form 6027 for Category 1 DG facilities or PSC Form 6028 for Category 2 to 4 DG facilities.
- (35) "Standard interconnection agreement" means PSC Form 6029 for Category 1 facilities or PSC Form 6030 for Category 2 to 4 DG facilities.
- Note: A copy of PSC Forms 6027 to 6030 can be obtained at no charge from your local electric utility or from the Public Service Commission, PO Box 7854, Madison, WI 53707–7854.
- (36) "Telemetry" means transmission of DG operating data using telecommunications techniques.
 - (37) "UL" means Underwriters Laboratory.
- (38) "Working day" has the meaning given in s. 227.01 (14), Stats.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

Subchapter II — General Requirements

PSC 119.03 Designated point of contact. Each public utility shall designate one point of contact for all customer inquiries related to DG facilities and from which interested parties can obtain installation guidelines and the appropriate standard commission application and interconnection agreement forms. Each public utility shall have current information concerning its DG point of contact on file with the commission.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

- PSC 119.04 Application process for interconnecting DG facilities. Public utilities and applicants shall complete the following steps regarding interconnection applications for all classes of DG facilities, in the order listed:
- (1) The public utility shall respond to each request for DG interconnection by furnishing, within 5 working days, its guidelines and the appropriate standard application form.
- (2) The applicant shall complete and submit the standard application form to its public utility.
- (3) Within 10 working days of receiving a new or revised application, the public utility shall notify the applicant whether the application is complete.
- (4) Within 10 working days of determining that the application is complete, the public utility shall complete its application review. If the public utility determines, on the basis of the application review that an engineering review is needed, it shall notify the applicant and state the cost of that review. For Categories 2 and 3, the cost estimate shall be valid for one year. For Category 4, the time period shall be negotiated but may not exceed one year. If the application review shows that an engineering review is not needed, the applicant may install the DG facility and need not complete the steps described in subs. (5) to (9).
- (5) If the public utility determines on the basis of the application review that an engineering review is needed, upon receiving from the applicant written notification to proceed and receipt of applicable payment from the applicant, the public utility shall complete an engineering review and notify the applicant of the results within the following times:

- (a) Category 1 DG application, 10 working days.
- (b) Category 2 DG application, 15 working days.
- (c) Category 3 DG application, 20 working days.
- (d) Category 4 DG application, 40 working days.
- (6) If the engineering review indicates that a distribution system study is necessary, the public utility shall include, in writing, a cost estimate in its engineering review. The cost estimate shall be valid for one year and the applicant shall have one year from receipt of the cost estimate in which to notify the public utility to proceed, except for a Category 4 DG application, in which case the time period shall be negotiated, but may not extend beyond one year. Upon receiving written notification to proceed and payment of the applicable fee, the public utility shall conduct the distribution system study.
- (7) The public utility shall within the following time periods complete the distribution system study and provide study results to the applicant:
 - (a) Category 1 DG application, 10 working days.
 - (b) Category 2 DG application, 15 working days.
 - (c) Category 3 DG application, 20 working days.
- (d) Category 4 DG application, 60 working days unless a different time period is mutually agreed upon.
- (8) The public utility shall perform a distribution system study of the local distribution system and notify the applicant of findings along with any distribution system construction or modification costs to be borne by the applicant.
- (9) If the applicant agrees, in writing, to pay for any required distribution system construction and modifications, the public utility shall complete the distribution system upgrades and the applicant shall install the DG facility within a time frame that is mutually agreed upon. The applicant shall notify the public utility when project construction is complete.
- (10) (a) The applicant shall give the public utility the opportunity to witness or verify the system testing, as required in s. PSC 119.30 or 119.31. Upon receiving notification that an installation is complete, the public utility has 10 working days, for a Category 1 or 2 DG project, or 20 working days, for a Category 3 or 4 DG project, to complete the following:
 - 1. Witness commissioning tests
- Perform an anti-islanding test or verify the protective equipment settings at its expense.
- Waive its right, in writing, to witness or verify the commissioning tests.
- (b) The applicant shall provide the public utility with the results of any required tests.
- (11) The public utility may review the results of the on-site tests and shall notify the applicant within 5 working days, for a Category 1 DG project, or within 10 working days, for a Category 2 to 4 DG project, of its approval or disapproval of the interconnection. If approved, the public utility shall provide a written statement of final acceptance and cost reconciliation. Any applicant for a DG system that passes the commissioning test may sign a standard interconnection agreement and interconnect. If the public utility does not approve the interconnection, the applicant may take corrective action and request the public utility to reexamine its interconnection request.
- (12) A standard interconnection agreement shall be signed by the applicant and public utility before parallel operation commences.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

PSC 119.05 Insurance and indemnification. (1) An applicant seeking to interconnect a DG facility to the distribution system of a public utility shall maintain liability insurance equal to or greater than the amounts stipulated in Table 119.05–1, per occurrence, or prove financial responsibility by another means mutually agreeable to the applicant and the public utility. For a

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DG facility in Category 2 to 4, the applicant shall name the public utility as an additional insured party in the liability insurance policy.

Table 119.05-1		
Category	Generation Capacity	Minimum Liability Insurance Coverage
1	20 kW or less	\$300,000
2	Greater than 20 kW to 200 kW	\$1,000,000
3	Greater than 200 kW to 1 MW	\$2,000,000
4	Greater than 1 MW to 15 MW	Negotiated

(2) Each party to the standard interconnection agreement shall indemnify, hold harmless and defend the other party, its officers, directors, employees and agents from and against any and all claims, suits, liabilities, damages, costs and expenses resulting from the installation, operation, modification, maintenance or removal of the DG facility. The liability of each party shall be limited to direct actual damages, and all other damages at law or in equity shall be waived.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

PSC 119.06 Modifications to the DG facility. The applicant shall notify the public utility of plans for any material modification to the DG facility by providing at least 20 working days of advance notice for a Category 1 DG facility, 40 working days for Category 2 DG facility, and 60 working days for a Category 3 or 4 DG facility. The applicant shall provide this notification by submitting a revised standard application form and such supporting materials as may be reasonably requested by the public utility. The applicant may not commence any material modifica-tion to the DG facility until the public utility has approved the revised application, including any necessary engineering review or distribution system study. The public utility shall indicate its written approval or rejection of a revised application within the number of working days shown in the table below. Upon completion of the application process, a new standard interconnection agreement shall be signed by both parties prior to parallel operation. If the public utility fails to respond in the time specified in Table 119.06-1, the completed application is deemed approved.

Table 119.06–1			
Category	Generation Capacity after Modification	Working Days for Utility's Response to Proposed Modifications	
1	20 kW or less	20	
2	Greater than 20 kW to 200 kW	40	
3	Greater than 200 kW to 1 MW	60	
4	Greater than 1 MW to 15 MW	60	

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

PSC 119.07 Easements and rights-of-way. If a public utility line extension is required to accommodate a DG interconnection, the applicant shall provide, or obtain from others, suitable easements or rights-of-way. The applicant is responsible for the cost of providing or obtaining these easements or rights of way.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

PSC 119.08 Fees and distribution system costs.

(1) Upon receiving a standard application form, the public utility shall specify the amount of any engineering review or distribution system study fees. Application fees shall be credited toward the cost of any engineering review or distribution system study. The applicant shall pay the fees specified in Table 119.08, unless the public utility chooses to waive the fees in whole or in part.

Table 119.08–1				
Category	Generation Capacity	Application Review Fee	Engineering Review Fee	Distribution System Study Fee
1	20 kW or less	None	None	None
2	Greater than 20 kW to 200 kW	\$250	Max. \$500	Max. \$500
3	Greater than 200 kW to 1 MW	\$500	Cost based	Cost based
4	Greater than 1 MW to 15 MW	\$1000	Cost based	Cost based

(2) The public utility may recover from the applicant an amount up to the actual cost, for labor and parts, of any distribution system upgrades required. No public utility may charge a commissioning test fee for initial start-up of the DG facility. The utility may charge for retesting an installation that does not conform to the requirements set forth in this chapter.

(3) Costs for any necessary line extension shall be assessed pursuant to s. PSC 113.1005.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

PSC 119.09 Disconnection. A public utility may refuse to connect or may disconnect a DG facility from the distribution

system only under any of the following conditions:

- Lack of approved standard application form or standard interconnection agreement.
 - (2) Termination of interconnection by mutual agreement.
- (3) Non-compliance with the technical or contractual requirements.
 - (4) Distribution system emergency.
- (5) Routine maintenance, repairs, and modifications, but only for a reasonable length of time necessary to perform the required work and upon reasonable notice.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

PSC 119.10

WISCONSIN ADMINISTRATIVE CODE

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PSC 119.10 One-line schematic diagram.

- (1) The applicant shall include a one-line schematic diagram with the completed standard application form. ANSI symbols shall be used in the one-line schematic diagram to show the following:
 - (a) Generator or inverter.
- (b) Point where the DG facility is electrically connected to the customer's electrical system
 - (c) Point of common coupling.
 - (d) Lockable interconnection disconnect switch.
- (e) Method of grounding, including generator and transformer ground connections
 - (f) Protection functions and systems.
- (2) The applicant shall include with the schematic diagram technical specifications of the point where the DG facility is electrically connected to the customer's electrical system, including all anti-islanding and power quality protective systems. The specifications regarding the anti-islanding protective systems shall describe all automatic features provided to disconnect the DG facility from the distribution system in case of loss of grid power, including the functions for over/under voltage, over/under frequency, overcurrent, and loss of synchronism. The applicant shall also provide technical specifications for the generator, lockable interconnection disconnect switch, and grounding and shall attach the technical specification sheets for any certified equipment. The applicant shall include with the schematic diagram a statement by the manufacturer that its equipment meets or exceeds the type tested requirements for certification.

 History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

PSC 119.11 Control schematics. For equipment not certified under s. PSC 119.26, the applicant shall include with the application a complete set of control schematics showing all protective functions and controls for generator protection and distribution system protection.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

PSC 119.12 Site plan. For all categories, the applicant shall include with the application a site plan that shows the location of the interconnection disconnect switch, adjoining street name, and the street address of the DG facility. For Category 2, 3, or 4 DG facilities, the site plan shall show the location of major equipment, electric service entrance, electric meter, interconnection disconnect switch, and interface equipment

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

Subchapter III — Design Requirements

- PSC 119.20 General design requirements. (1) The applicant shall install protection devices to ensure that the current supplied by the DG facility is interrupted if a fault or other potentially dangerous event occurs on the distribution system. If such an event occurs and the public utility's distribution system is deenergized, any DG facility that is connected to this distribution system shall automatically disconnect. All DG facilities shall utilize protection devices that prevent electrically closing a DG facility that is out of synchronization with the distribution system.
- (2) All installations shall include equipment circuit breakers, on the DG facility side of the point where the DG facility is electrically connected to the customer's electrical system, that are capable of interrupting the maximum available fault current. Equipment circuit breakers shall meet all applicable UL, ANSI, and IEEE standards
- (3) The public utility may require that the applicant furnish and install an interconnection disconnect switch that opens, with a visual break, all ungrounded poles of the interconnection circuit. The interconnection disconnect switch shall be rated for the voltage and fault current requirements of the DG facility, and shall meet all applicable UL, ANSI, and IEEE standards. The switch

enclosure shall be properly grounded. The interconnection disconnect switch shall be accessible at all times, located for ease of access to public utility personnel, and shall be capable of being locked in the open position. The applicant shall follow the public utility's recommended switching, clearance, tagging, and locking procedures.

Note: Provisions of the Wisconsin Electrical Safety Code, Volume 2, ch. Comm 16 also apply to these installations.

- (4) The applicant shall label the interconnection disconnect switch "Interconnection Disconnect Switch" by means of a permanently attached sign with clearly visible and permanent letters. The applicant shall provide and post its procedure for disconnecting the DG facility next to the switch
- (5) The applicant shall install an equipment grounding conductor, in addition to the ungrounded conductors, between the DG facility and the distribution system. The grounding conductors shall be available, permanent, and electrically continuous, shall be capable of safely carrying the maximum fault likely to be imposed on them by the systems to which they are connected, and shall have sufficiently low impedance to facilitate the operation of overcurrent protection devices under fault conditions. All DG transformations shall be multi-grounded. The DG facility may not be designed or implemented such that the earth becomes the sole fault current path.

Note: Grounding practices are also regulated by the Wisconsin Electrical Safety Code Volumes 1 and 2, as found in chs. Comm 16 and PSC 114.

- (6) (a) Certified paralleling equipment shall conform to UL 1741 (January 17, 2001 Revision) or an equivalent standard as determined by the commission.
- (b) Non-certified paralleling equipment shall conform to the requirements of IEEE 1547.

Note: The UL standards are available at http://ulstandardsinfonet.ul.com, and IEEE standards are available at http://ieee.org. They may also be viewed at the PSCW Library, 610 N. Whitney Way, Madison, WI.

- (7) (a) All Category 1 and 2 DG facilities shall be operated at a power factor greater than 0.9.
- (b) All Category 3 and 4 DG facilities shall be operated at unity power factor or as mutually agreed between the public utility and
- (8) The DG facility shall not create system voltage or current disturbances that exceed the standards listed in subch. VII of ch.
- (9) The applicant shall protect and synchronize its DG facility with the distribution system
- (10) Each DG facility shall include an automatic interrupting device that is listed with a nationally recognized testing laboratory and is rated to interrupt available fault current. The interrupting device shall be tripped by any of the required protective functions.
- (11) An applicant for interconnection of a Category 3 or Category 4 facility shall provide test switches as specified by the public utility, to allow for testing the operation of the protective functions without unwiring or disassembling the equipment.
- (12) The public utility may require a DG facility to be isolated from other customers by installation of a separate power transformer. When a separate transformer is required, the utility may include its actual cost in the distribution system upgrade costs. The applicant is responsible for supplying and paying for any custom transformer. This requirement does not apply to an induction-type generator with a capacity of 5 kW or less, or to other generating units of 10 kW or less that utilize a line-commutated
- (13) The owner of a DG facility designed to operate in parallel with a spot or secondary network service shall provide relaying or control equipment that is rated and listed for the application and is acceptable to the public utility.
- (14) For a Category 3 or Category 4 DG facility, the public utility may require that the facility owner provide telemetry equipment whose monitoring functions include transfer-trip function-

106-9 PUBLIC SERVICE COMMISSION

PSC 119.40

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ality, voltage, current, real power (watts), reactive power (vars), and breaker status.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

PSC 119.25 Minimum protection requirements. (1) Each DG facility shall include protection and anti-islanding equipment to prevent the facility from adversely affecting the reliability or capability of the distribution system. The applicant shall

equipment to prevent use factory from adversery affecting the ferability or capability of the distribution system. The applicant shall contact the public utility to determine any specific protection requirements.

- (2) The protective system functions, which may be met with microprocessor—based multifunction protection systems or discrete relays, are required. Protective relay activation shall not only alarm but shall also trip the generator breaker/contactor.
- (3) In addition to anti-islanding protection, a DG facility shall meet the following minimum protection requirements:
 - (a) A Category 1 DG facility shall include:
 - 1. Over/under frequency function.
 - 2. Over/under voltage function.
 - 3. Overcurrent function.
 - 4. Ground fault protection.
 - (b) A Category 2, 3, or 4 DG facility shall include:
 - 1. Over/under frequency function.
 - Over/under voltage function.
 - 3. Overcurrent function.
 - Ground fault protection.
 - 5. Synchronism check function.
- 6. Other equipment, such as other protective devices, supervisory control and alarms, telemetry and associated communications channel, that the public utility determines to be necessary. The public utility shall advise the applicant of any communications requirements after a preliminary review of the proposed installation.
- (4) A DG facility certified pursuant to s. PSC 119.26 shall be deemed to meet the requirements of this section.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

Subchapter IV — Equipment Certification

PSC 119.26 Certified paralleling equipment. DG paralleling equipment that a nationally recognized testing laboratory certifies as meeting the applicable type testing requirements of UL 1741 (January 17, 2001 revision) is acceptable for interconnection, without additional protection systems, to the distribution system. The applicant may use certified paralleling equipment for interconnection to a distribution system without further review or testing of the equipment design by the public utility, but the use of this paralleling equipment does not automatically qualify the applicant to be interconnected to the distribution system at any point in the distribution system. The public utility may still require an engineering review to determine the compatibility of the distributed generation system with the distribution system capabilities at the selected point of common coupling.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

PSC 119.27 Non-certified paralleling equipment.

- (1) Any DG facility that is not certified under s. PSC 119.26 shall be equipped with protective hardware or software to prevent islanding and to maintain power quality. The applicant shall provide the final design of this protective equipment. The public utility may review and approve the design, types of protective functions, and the implementation of the installation. The applicant shall own the protective equipment installed at its facility.
- (2) The applicant shall calibrate any protective system approved under sub.(1) to the specifications of the public utility. The applicant shall obtain prior written approval from the public utility for any revisions to specified protection system calibrations.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

Subchapter V — Testing of DG Facility Installations

PSC 119.30 Anti-islanding test. The public utility may perform an anti-islanding test or observe the automatic shutdown before giving final written approval for interconnection of the DG facility. The anti-islanding test requires that the unit shut down upon sensing the loss of power on the distribution system. This can be simulated by either removing the customer meter or opening a disconnection switch while the generator is operating. Voltage across the customer side of the meter or disconnection switch shall be measured and must be observed to reduce to zero within two seconds after disconnection. The test shall be conducted with the generation as close to its full output as possible. If a voltage is sustained after the disconnection, approval of the installation shall not be given until corrective measures are taken with a subsequent successful shutdown test.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

PSC 119.31 Commissioning tests for paralleling equipment in Categories 2 to 4. The public utility shall provide the acceptable range of settings for the paralleling equipment of a Category 2, 3, or 4 DG facility. The applicant shall program protective equipment settings into this paralleling equipment. The public utility may verify the protective equipment settings prior to allowing the DG facility to interconnect to the distribution system.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

PSC 119.32 Additional test. The public utility or applicant may, upon reasonable notice, re–test the DG facility installation. The party requesting such re-testing shall bear the cost of the re-tests.

History: CR 03-003: cr. Register January 2004 No. 577, eff. 2-1-04.

PSC 119.40 Right to appeal. The owner of a generating facility interconnected or proposed to be interconnected with a utility system may appeal to the commission should any requirement of the utility service rules filed in accordance with the provisions of this chapter be considered excessive or unreasonable, Such appeal will be reviewed and the customer notified of the commission's determination.

History: CR 03–003: renum. from PSC 113.0208 and am. Register January 2004 No. 577, eff. 2-1-04.

I. INDEMNIFICATION.

(Note: "Project Developer" and/or "Customer" should be defined for the intent to be one and the same or 2 different parties to be clarified throughout. The terms "Customer" and "Company" have been used in this document, but may need to be modified based on how the parties are defined).

17. INDEMNIFICATION

A. Customer covenants and agrees that it shall defend, indemnify and hold Company, and all of its officers, agents and employees harmless for any claim, loss, damage, cost, charge, expense, lien, settlement or judgment, including interest thereon, whether to any person, including employees of Customer, its Subcontractors and Suppliers, or property or both, arising directly or indirectly out of or in connection with Customer's or any of its Subcontractor's or Suppliers performance of the Agreement or in connection with the performance of the Agreement, to which Company or any of its officers, agents or employees may be subject or put by reason of any act, action, neglect or omission on the part of Customer, any of its Subcontractors or Suppliers or Company, or any of their respective officers, agents and employees. Without limiting the foregoing, said obligation includes claims involving Customer's, Supplier's or Subcontractor's employees injured while going to and from the premises. If the Agreement is one subject to the provisions MCL 691.991, then Customer shall not be liable under this section for damage to persons or property directly caused or resulting from the sole negligence of Company, or any of its officers, agents or employees.

B. In the event any suit or other proceedings for any claim, loss, damage, cost, charge or expense covered by Customer's foregoing indemnity should be brought against Company or any of its officers, agents or employees, Customer hereby covenants and agrees to assume the defense thereof and defend the same at Customer's own expense and to pay any and all costs, charges, attorney's fees, and other expenses, and any and all judgments that may be incurred by or obtained against Company or any of its officers, agents, or employees in such suits or other proceedings. In the event of any judgment or other lien being placed upon the property of Company in such suits or other proceedings,

Attachment No. 2 to Utility Comments
July 6, 2007
DTE Indemnification Language and Insurance Requirements (Attachment A)

Customer shall at once cause the same to be dissolved and discharged by giving bond or otherwise.

II. Insurance

18. Customer shall provide Detroit Edison with Certificate(s) of Insurance evidencing that insurance coverages of the types and amounts as specified in the Appendix to the Agreement entitled "Insurance to be provided by Customer" are in effect.

Customer affirms to Detroit Edison that such insurance coverage will remain in effect during the installation of customer-generator's facility.

Insurance to be Provided by the Contractor/Supplier (CONTRACTOR)

Before the CONTRACTOR or their Subcontractors DO ANY WORK under the Contract, the CONTRACTOR SHALL FURNISH TO DTE Energy and its subsidiaries CERTIFICATE(S) OF INSURANCE evidencing that insurance has been provided to meet, at minimum, the requirements as set forth in this Appendix. It is expressly understood that the obtaining or maintenance of insurance as is herein required, shall in no way limit or release CONTRACTOR's or Subcontractor's liability under the indemnification provisions of the agreement or contract for which this insurance is provided.

Type of Insurance

Minimum Limits and Coverage

1. Workers' Compensation:

Statutory requirements for the State of Michigan and/or

for the state where the work will be performed.

2. Employers' Liability:

\$ 1,000,000 each person

3. Business Automobile Policy when applicable (see Section 8.(e) herein). Applies to Owned, Non-Owne and Hired:

Combined Single Limit

Bodily Injury and Property Damage

\$5,000,000 each occurrence

4. Commercial General Liability (The limits required may be satisfied by a combination of primary and/or excess coverage):

Combined Single Limit

Bodily Injury and Property Damage

\$5,000,000 each occurrence

If overhead electric line work, tree trimming/line

clearance or attaching to utility poles:

Combined Single Limit

Bodily Injury and Property Damage

\$10,000,000 each occurrence

AND

CONTRACTOR'S and/or its Subcontractors' COVERAGE SHALL:

- Include DTE Energy and its subsidiaries as additional insured. Such additional insured status shall (i) be provided by an endorsement at least as broad as the appropriate Insurance Services Office (ISO) endorsement (See Section 6. herein).
- Include a cross liability clause. (ii)
- Provide that insurers who satisfy these requirements may not cancel, non-renew, materially alter or (iii) reduce coverage or limits unless they have delivered thirty (30) day's prior written notice to Corporate Insurance, DTE Energy.
- (iv) Be primary to any potentially applicable insurance carried by or arranged for DTE Energy and its subsidiaries.
- Provide that the contractor's insurer shall have no rights of recovery, by subrogation or otherwise, (v) against DTE Energy and its subsidiaries.
- Include blanket contractual coverage. (vi)
- Include products and/or completed operations coverage for a period of at least two (2) years after the (vii) completion of the service or work
- If it is applicable or becomes applicable to the work under the Contract, provide Professional (viii) Liability Insurance and/or Errors & Omissions Liability Insurance with combined single limits of at least \$5,000,000 (satisfied by separate policy if needed).
- Contain no exclusions for explosion, collapse or underground property damage hazards (XCU (ix) coverage).
- (x) If it is applicable or becomes applicable to the work under the Contract, provide Pollution/Environmental Impairment Liability Insurance with limits of at least \$5,000,000 per occurrence (satisfied by separate policy if needed).

Insurance to be Provided by the Contractor/Supplier (CONTRACTOR)

- 5. Initial certificates of insurance and other evidence of coverage are to be provided to the buyer in the supply chain and become a part of the Contract. All Contractor's certificates of insurance shall state in the Special Provisions section: "DTE Energy and its subsidiaries are additional insureds and the above listed liability insurance includes blanket contractual coverage". All certificates must also state that no material change or cancellation can be effective without thirty (30) days prior written notice to Supply Chain, DTE Energy. Immediately upon renewal, rewrite or new issue of its insurance coverage, Contractor shall provide to Supply Chain all such certificates of insurance and other evidence of coverage to satisfy all of the provisions herein. Such certificates should be sent to Supply Chain, RE: Contractor Certificate, DTE Energy, 2000 2nd Avenue, 505 WCB, Detroit, MI 48226.
- 6. In addition to providing certificates of insurance, Contractor shall provide a copy of its broad additional insured endorsement (or that section of its policy) that states that DTE Energy and its subsidiaries are additional insureds on Contractor's liability policies (see Section 4.(i) herein).
- 7. Contractor expressly understands and agrees that any discussion, negotiation or acceptance of a certificate of insurance by DTE Energy and its subsidiaries is expressly understood NOT to constitute a review or approval of the CONTRACTOR's or Subcontractor's insurer, insurance coverage or available limits, or a waiver or modification of any of the insurance requirements described herein.
- 8. Should any of the work:
 - (a) Be upon or contiguous to navigable bodies of water or subject to Admiralty jurisdiction, CONTRACTOR and/or its Subcontractors shall also carry insurance covering their employees for benefits available and insurance against employer's liabilities under the Federal Longshoremen's and Harbor Workers' Act (44 U.S. Stat. 1424 (as amended)) and under the Jones Act (41 U.S. Stat. 988 (as amended)) or under the General Maritime Law.
 - (b) Involve watercraft owned, hired or operated by the CONTRACTOR and/or its Subcontractors, CONTRACTOR and/or its Subcontractors shall also provide coverage for liability arising out of such watercraft with a combined single limit not less than \$5,000,000 each occurrence. If the hull is insured, such insurance shall contain the insurer's waiver of subrogation rights against DTE Energy and its subsidiaries. All relevant provisions of these insurance requirements also apply to this specific requirement.
 - (c) Involve aircraft (fixed wing or helicopter) owned, hired or operated by the CONTRACTOR and/or its Subcontractors, then CONTRACTOR and/or its Subcontractors shall also provide coverage for liability arising out of such aircraft with a combined single limit of not less than \$50,000,000 each occurrence and such limit shall apply to Bodily Injury (including passengers) and Property Damage. If the craft is insured, such insurance shall contain the insurer's waiver of subrogation rights against DTE Energy and its subsidiaries. All relevant provisions of these insurance requirements also apply to this specific requirement.
 - (d) Involve licensed vehicle(s) utilized within the scope of work performed under the Contract, CONTRACTOR and/or its Subcontractors shall provide evidence of Automobile Liability Insurance coverage as outlined in Section 3 herein.
 - (e) Involve interstate or intrastate transportation of hazardous cargoes as defined by the Motor Carrier Act of 1980 (as amended), CONTRACTOR and/or its Subcontractors shall provide evidence of compliance with the financial responsibility requirements of the Motor Carrier Act (Form MCS-90 or guarantee bond (as amended)).
 - (f) Be within 50 feet of any railroad property, CONTRACTOR and its subcontractors shall each maintain a Railroad Protective Liability Insurance Policy naming the railroad(s) as named insureds, for an amount of not less than the greater of \$5,000,000 per occurrence or the limit of insurance required by the owner of the railroad property.
- 9. The provisions of the various insurance policies and the insurers issuing such policies are subject to DTE Energy's and/or its subsidiaries' approval and a copy of the applicable insurance policies shall be furnished by the CONTRACTOR at the request of DTE Energy and/or its subsidiaries.
- 10. All deductibles or retentions on any of the policies of insurance required herein shall be for the account of the Contractor.

Grow It * Use It * Renew It

In Ohio: 7155 Five Mile Road, Cincinnati, OH 45230 In Michigan: 1510 62nd Street, Fennville, MI 49408 Phone 513-265-2758 * Fax 513-233-3395 * email: Normacnc5@aol.com

July 8, 2007

Ms. Julie Baldwin Michigan Public Service Commission

Subject: COMMENTS ON DRAFT DOCUMENT, 30kW & LARGER

INTERCONNECTION PROCEDURES

Dear Ms. Baldwin:

This provides our comments to the draft document circulated for discussion at the June 19, 2007 meeting of the 30kW & Larger Interconnection Procedures Workgroup. We support the draft with the following exceptions:

- 1. In order to provide simple and effective tracking of the timeframe under which an application and interconnection are completed, we recommend a one-page cover document with each of the steps in the process, and columns to fill in the date completed, and initials by the utility and the developer. The document would also contain the contacts for each party. Any issues which delay interconnection would also be noted on this single page, using supplemental documents for detailed information.
- 2. We recommend that information for Section 4 (types 1, 2, and 3 interconnection location decisions) be available at the pre-application meeting outlined in Section 1.1.
- 3. While we understand that the rate which developers will be paid for any power sold to the utility is currently outside the scope of the interconnection procedures discussion, we recommend that costs for interconnection be creditable against the first year's power sales by the developer.

Sincerely,

Norma S. McDonald Operating Manager



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BY ELECTRONIC MAIL

July 10, 2007

Ms. Julie Baldwin, and Mr. Brian Mills Michigan Public Service Commission 6545 Mercantile Way Lansing, Michigan 48909

In re: Docket 15113 -30+ kW Interconnection Standards Comments of American Transmission Company (ATC)

Dear Ms. Baldwin and Mr. Mills:

This letter responds to your invitation to comment on the draft "MPSC Staff Strawman Proposals for Improvements to Interconnection Procedures", which relates to interconnection standards for distribution-interconnected generators of 30 kW or greater and was discussed at the June 19, 2007 meeting of the Commission Staff. This letter addresses recommendation #3 in the Commission Staff's proposal.

ATC filed comments with the Commission on April 20, 2007 indicating the need for consultation between the distribution and transmission utilities and providing guidelines for when this consultation should occur. ATC also indicated that the transmission owner would need 10 to 15 days to determine and report if further study was necessary. We are pleased that the Commission Staff has considered our comments and incorporated some of our suggestions into the Commission Staff's proposal. ATC is pleased to provide the following additional comments on the generation to distribution interconnection process.

ATC re-iterates that in most cases where generation seeks to interconnect to distribution voltage facilities, ATC, as the transmission owner, can assess interconnection impacts on the transmission system concurrent with utility studies, and only in a few cases does ATC believe additional study time would be needed to evaluate the impact of the proposed interconnection on the transmission system.

Staff Recommendations and ATC comments

Recommendation 3.1: Identify threshold of when the distribution utility must notify the transmission utility of a proposed generator interconnection to the distribution system.

ATC is pleased that the Commission Staff has incorporated a modified version of the threshold test suggested in our previous comments. ATC agrees with the notion that the interconnection process should not be unnecessarily delayed by involvement of a transmission owner unless the specific circumstances of a particular interconnection warrant that involvement.

Ms. Julie Baldwin and Mr. Brian Mills July 11, 2007 Page 2 of 3

ATC requests that the Commission Staff consider two modifications to recommendation 3.1. In ATC's comments filed on April 20, 2007, ATC noted the following suggested threshold test:

The alternative threshold tests that ATC would recommend are: Where a single generator request or the aggregation of existing and new generation, measured at the transmission-to-distribution (T-D) point of interconnection, exceeds a) the minimum distribution load or, b) the total connected generation is 10 MVA or greater, transmission consultation should be required. (These are the two alternate tests.) In these cases some, but not most, interconnection requests will require detailed study.

The current wording of recommendation 3.1 does not incorporate an evaluation by the distribution utility of whether or not the aggregation of existing distribution connected generation and the proposed generator interconnection exceed either of the two thresholds in the notification test. As previously noted, this aggregation would be measured at the transmission-to-distribution (T-D) point of interconnection. As such, the distribution utility, and not the interconnection customer, would need to make this evaluation. ATC believes this evaluation is important since generators operating in parallel on the electric grid have a cumulative effect on the electric network that must be taken into account in evaluating the impact of any new or increased generating capacity.

As noted above, ATC does not intend to burden the interconnection process with unnecessary process steps. Therefore, although the Commission Staff has proposed a 2 MW threshold as one part of their test, ATC believes that raising this threshold to a higher value, such as 10 MW, would serve both the interests of reliability and efficiency in the interconnection process. If the Commission Staff incorporates the suggestion that an aggregation of existing and proposed generation should be considered, then ATC strongly encourages the Commission Staff to raise the MW threshold test to avoid unnecessary evaluation by the transmission owner.

Recommendation 3.2: Transmission utility notification regarding participation in a study.

ATC agrees with the Commission Staff that the transmission owner should expeditiously review information supplied by the distribution utility and should expeditiously indicate if study of the potential transmission system impacts must be undertaken. ATC believes that ensuring timely review of an interconnection customer's application assures non-discriminatory treatment and also makes good business sense. ATC suggests that the Staff recommendation be modified to permit adequate flexibility in the study schedule when a particular interconnection request warrants it.

In recommendation 3.2, ATC believes that the Commission Staff proposal inadvertently introduces inflexibility into the interconnection process by requiring the transmission owner (and the Midwest Independent Transmission System Operator, Inc.) to conform to the distribution utility's study schedule. As ATC noted in its comments filed on April 20, 2007,

Simply put, most generator-to-distribution (G-D) interconnections will require no transmission system impact study and would likely also not require any transmission impact mitigation. Some interconnections to distribution facilities, however, may have material, adverse impacts on the reliable operation of the adjacent, interconnected transmission system and would "trigger" the need for some form of transmission system impact study.

ATC would anticipate that such a study, in most cases, could be completed in 10 to 15 days, and could be done concurrent with the distribution company analysis of its system. A few interconnections, however, could require 90 or more days for impact and mitigation studies. Whether a more detailed analysis would

Ms. Julie Baldwin and Mr. Brian Mills July 11, 2007 Page 3 of 3

be required, could likely be determined in the first 15 days following receipt of the necessary information concerning the generator and the proposed interconnection. With that determination, the transmission owner could also provide preliminary estimates of scope of the study, the cost of the study and time required to perform the detailed analysis.

ATC suggests that the Commission Staff include the following language to ensure flexibility for the transmission owner in those rare instances when a more detailed impact and mitigation study is required. In the strawman, after para. 3,2, add:

"In the TO response to the distribution utility, the TO should provide a good faith estimate of the time required to perform a transmission impact study."

This language will ensure, for example, that studies of large generator interconnections to the distribution utility are not inadvertently forced into a restricted study schedule that would not permit proper evaluation of system reliability and safety, or that developers are not misled into expecting a complete study and response when circumstances may require more time. It has been ATC's experience that developers seeking to interconnection large generators to the distribution network understand the need for longer, more detailed studies and ATC does not believe that this flexibility will result in inappropriate delays for an interconnection customer. An example of a large generator interconnection to a distribution utility can be found at the following web link:

http://oasis.midwestiso.org/documents/ATC/G225_Facility_Study_Report.pdf

Recommendation 3.3: Transmission utility response requirements.

ATC agrees with the Commission Staff's proposal that the transmission utility respond to the distribution utility within 10 business days as to whether or not the transmission utility will participate in system studies but believes that notification of receipt of a request within 3 business days by the transmission owner is an unnecessary process step. The Commission Staff could state that "the transmission owner should respond within 10 business days. If the transmission owner does not respond, the distribution utility may assume that no transmission impacts need to be considered." This approach will reduce the burden on the transmission owner to meet short deadlines that only confirm receipt of a request and allow the transmission owner to focus on evaluating whether or not a study of potential transmission system impacts is warranted.

Thank you for this opportunity to comment.

Sincerely,

/s/ Jay A. Porter

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